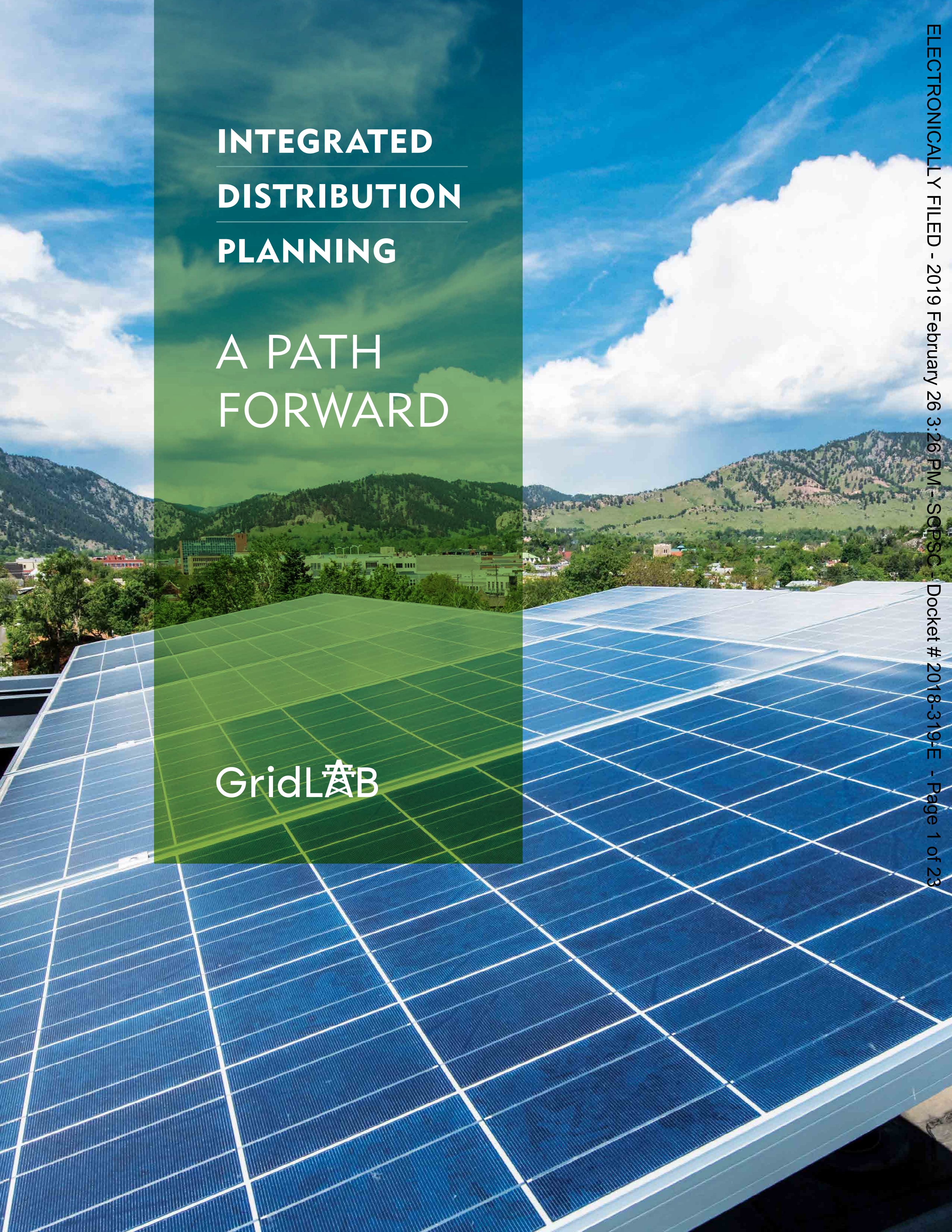

INTEGRATED DISTRIBUTION PLANNING

A PATH FORWARD

GridLAB

GridLAB

ABOUT GRIDLAB

GridLab provides comprehensive and credible technical expertise on the design, operation, and attributes of a flexible and dynamic grid to assist policy makers, advocates, and other energy decision makers in navigating the energy transformation.

ABOUT THE AUTHOR

Curt Volkmann is President of New Energy Advisors, LLC and a member of the GridLab network. He has over 34 years of experience in the utilities industry including 9 years as a distribution planning engineer for Pacific Gas & Electric and 18 years with Accenture advising U.S. and international gas, electric and water utilities. As an independent consultant, he currently supports clients across multiple states in a variety of regulatory proceedings related to distribution system planning, distributed energy resources, and grid modernization. Among other engagements, he assists clients in the California Distribution Resources Plan (DRP), Illinois NextGrid, Minnesota Investigation into Grid Modernization, New York Reforming the Energy Vision (REV), and Ohio PowerForward proceedings.

Cover and page 4 photos courtesy of NREL

INTEGRATED DISTRIBUTION PLANNING

A PATH FORWARD

TABLE OF CONTENTS

EXECUTIVE SUMMARY

Electric distribution utilities have successfully designed and operated safe and reliable distribution systems for over 100 years using proven, but not publicly understood, distribution planning practices. As customers increasingly adopt distributed energy resources (DER) such as energy efficiency, demand response, distributed generation, combined heat and power, electric vehicles, and storage, it becomes important for utilities to proactively determine how to best take advantage of these resources to minimize costs while maintaining service quality. It also becomes important for regulators to more clearly understand the rationale and justification for utilities' proposed grid modernization investments in light of this increased DER adoption to ensure prudency and cost-effectiveness. With a well-designed and transparent distribution planning process, regulators can lower overall distribution system costs and save money for customers. This requires the development of new capabilities in distribution planning for it to become a valuable tool for guiding utility investment and marketplace activity.

Many state regulatory commissions and utilities are addressing this transition to Integrated Distribution Planning (IDP) to lower costs and enhance customer relationships. This paper was developed for the Public Utilities Commission of Ohio's PowerForward proceeding and provides a synthesis of existing literature on IDP and activity in various states, a summary of anticipated changes and new required capabilities, and recommendations for regulators on potential next steps for beginning the transition to IDP.

New IDP capabilities include:

- **Advanced Forecasting and System Modeling**
  Enhanced forecasting to reflect the uncertainty of DER growth, more detailed system modeling of loads and DER impacts on the distribution system.
- **Hosting Capacity Analysis**
  Determining how much additional DER each distribution circuit can accommodate without requiring upgrades.
- **Disclosure of Grid Needs and Locational Value**
  Identification and publication of opportunities for DER to provide grid services as non-wires alternatives; identification and publication of locations on each circuit where DER deployment can provide grid benefits.
- **New Solution Acquisition**
  Acquiring or sourcing DER from customers and third parties to provide grid services using pricing, programs

or procurement. For example, using the peak demand reduction capability of smart thermostats in a targeted way to reduce circuit peak loads and avoid the need for circuit or substation upgrades.

- **Meaningful Stakeholder Engagement**
  Establishing processes for open dialogue, transparent information sharing, collaboration, and consensus building among stakeholders.

DER ADDRESSING DISTRIBUTION GRID NEEDS

Central Hudson Gas & Electric in New York is targeting deployment of smart Wi-Fi thermostats and pool pump controls to reduce local distribution peak demand by 16 MW in select areas. Michael Mosher, President and CEO of Central Hudson, explained "Through our Peak Perks program, we've identified areas and specific circuits that are approaching capacity on peak days and may require future upgrades to reliably serve customers when energy use is highest, typically on the hottest summer days when the use of air conditioning is maximized. By working with our customers to control energy use in these locations on peak days, we are seeking to avoid or postpone system upgrades in these areas, ultimately saving money for all our customers."[1]

Even for states where customer adoption of DER is lower than other states referenced in this paper, it is not too early to take proactive steps toward establishing the new IDP capabilities, and begin taking advantage of existing DER resources, such as energy efficiency and demand response. GridLab recommends the following next steps for regulatory commissions that are in the early stages of the transition to IDP:

1 | Establish clear objectives and guiding principles for the development of IDP, including the extent to which the commission intends to establish an open market for distribution grid services.

2 | Require each utility to file a report describing its current distribution planning process and any planned improvements or investments in improved capabilities. The report should include proposed hosting capacity use cases and methodologies, proposed non-wires alternative (NWA) suitability criteria and the identification of candidate capacity, voltage or reliability projects for NWA pilots that would cost-effectively substitute DER for planned distribution investments. These reports will reveal similarities and differences in utility approaches and provide a common understanding of the starting points for each utility in building new capabilities for the transition to IDP.

3 | Establish an IDP Technical Working Group applying the best practices for stakeholder engagement referenced in this paper and involving the commission staff, all utilities, and all interested stakeholders. The Technical Working Group should develop recommendations to the commission on the following:

a. Future scenarios for customer DER adoption across the state, and how these scenarios should be incorporated into forecasting and transmission, distribution, and integrated resource planning processes.

b. Modifications to interconnection standards defining required functions and settings for advanced inverters.

c. Development of NWA suitability criteria, and a process and timeline for implementing pilots identified in the utility reports from step 2.

d. Definition of hosting capacity analysis (HCA) use cases; identification of the appropriate HCA methodology and associated tools and data requirements to satisfy the use cases; and a timeline for initial HCA analysis and publication of results for each utility.

d. Development of portals for sharing information on circuit load profiles, peak load forecasts, capital investment plans, hosting capacity maps, heat maps reflecting locational value and other key data.

1 https://www.cenhud.com/news/news/july15_2016. For program details, see https://www.cenhubpeakperks.com

INTRODUCTION

The current electric distribution systems in the U.S. have provided safe and reliable delivery of electricity to consumers for over 100 years. Using proven but not publicly understood planning practices, distribution engineers have designed the systems to accommodate one-way power flow from bulk transmission to end-use customers, and sufficiently sized the systems to meet projected peak loads in each local area.

Technological advancements in distributed energy resources, rapid cost declines, and consumer interest in clean energy are causing two significant market changes: customers adopting distributed energy solutions–in some places quite rapidly–and utilities thinking proactively about how to pursue new opportunities to take advantage of these technologies.[2]

The industry is transitioning to a future in which distributed energy resources[3] (DER) will play an important role in providing grid services when and where they are needed most. To fully realize the value of these DER and save money for customers, distribution planning must evolve from a largely closed process to one that provides transparency into distribution system needs, explicitly considers DER growth and DER capabilities, and ensures that these capabilities are fully utilized to address system needs.[4]

At least 15 states have proceedings planned or underway related to electric distribution system planning[5] and there is extensive literature available on the evolution of distribution planning and related topics. As input into the Public Utilities Commission of Ohio's PowerForward proceeding, the author reviewed over 35 papers, articles, presentations, and other publications related to distribution planning (*see References list beginning on page* 22). This paper provides a synthesis of the existing literature on IDP and activity in several states, a summary of anticipated changes and new required capabilities, and recommendations for regulatory commissions on potential next steps.

2 Robison, Pickles, Fine, Sakib, and Duffy, p. 1

3 DER include energy efficiency, demand response or other active load management, combined heat and power (CHP), distributed generation such as photovoltaic (PV) solar or wind, stationary energy storage, electric vehicles and microgrids.

4 Gahl, Smithwood, and Umoff, p. 2

5 Homer, Cooke, Schwartz, Leventis, Flores-Espino, and Coddington, p. iv

TODAY'S DISTRIBUTION PLANNING

Distribution Planning (DP) involves a set of activities performed by utilities to assess the grid's performance under changing future conditions and to identify and implement solutions to proactively address identified needs.[6] Typical DP activities include:

- Forecasting future circuit and substation loads and peak demands.
- Power flow modeling and system assessment to determine if the existing grid can accommodate forecasted demand, maintain adequate voltage, and safely operate during normal and abnormal system conditions. The system assessment also typically includes a review of system reliability and components at risk of failure, which may require refurbishment or replacement.
- Identification of grid needs[7] and solutions to address the needs. Utilities typically identify multiple alternatives to address needs, ranging from low cost (e.g., reconfiguring a circuit) to higher cost (e.g., reconductoring a circuit, adding a new circuit or substation, etc.).
- Prioritization of solutions and development of capital and operations and maintenance (O&M) plans and associated budgets.
- Design and support for construction of various projects to address grid needs.
- Ongoing monitoring and control of the distribution system, including adjustments to equipment settings or circuit configurations as load conditions change.

The typical utility distribution planning process (*see Figure 1*) has historically been the exclusive domain of utility engineers, offering limited external stakeholder or regulator visibility into the utility's underlying data, assumptions, methodologies or calculations. There are periodic opportunities for stakeholders to examine a utility's distribution investment plan through general rate case proceedings, but this is often a very contentious, time consuming, and resource intensive process for regulators and other parties.

6 Rhode Island, p. 43.

7 Grid needs may include additional capacity to meet peak loads during normal or emergency conditions, voltage regulation, reactive power compensation, system protection modifications, increased hosting capacity, equipment replacement, or other investments to improve reliability or power quality.

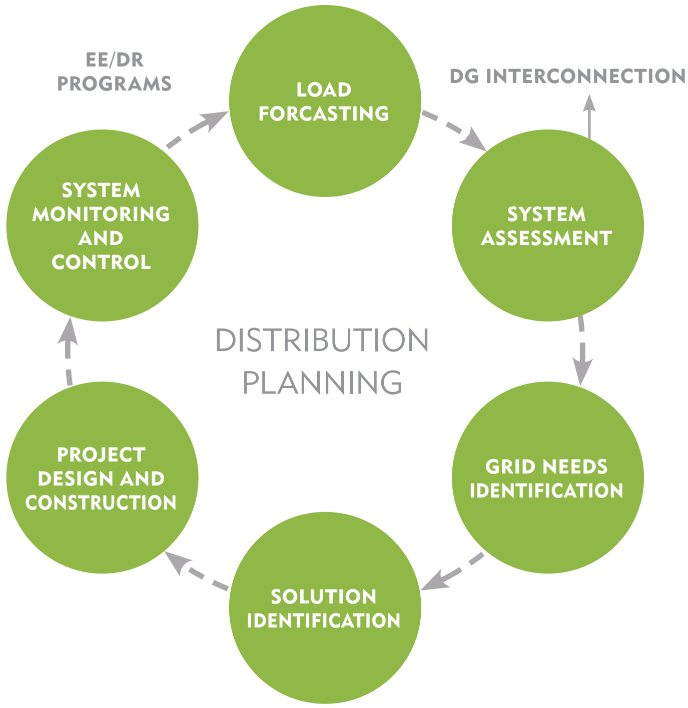

FIGURE 1. Typical Distribution Planning Process

Today, solutions to address grid needs are typically limited to traditional utility equipment (poles, wires or cable, transformers, voltage regulators, etc.). In cases where utilities are piloting the deployment of DER to provide grid services, they strongly prefer to own and directly control the DER assets. Opportunities for third parties to participate in providing non-traditional DER solutions have to date been very limited.

Distribution planners often take a reactive approach to the proliferation of distributed energy resources, treating DER as problems to be addressed or behind-the-meter activities to be ignored rather than opportunities to be embraced and integrated. Energy efficiency and demand response programs are typically disconnected from distribution planning and not considered as potential resources to address grid needs. For distributed generation (DG), utilities provide little guidance to customers and developers, who themselves decide the type, size and location of DG to install and how they will operate it. Utilities must then manage integration of the DG even though the location may be unfavorable and lead to expensive interconnection. Although utilities often compensate customers through net metering or a fixed tariff, the compensation may not reflect the full value that could be provided by the resource.[8]

8 Lew, p. 4

With increasing numbers of customer and developer applications to interconnect DG to the distribution system, utilities often lack a close integration between the interconnection and distribution planning processes. It is not uncommon for the distribution system models used in planning to lack any details about installed or planned DER. As described later, the impacts of existing and anticipated DER (including energy efficiency and demand response) are often not included in a utility's distribution system local load forecast, a foundational element in determining its need for capital investment.

KEY CHANGES

In today's evolving utility industry, a diverse set of DER technologies offer the potential to substitute for conventional utility infrastructure solutions. Although many of these technologies are not new, their pace of deployment is accelerating as falling technology costs drive market maturity and broader consumer adoption.[9]

In many cases, these DER solutions are financed, installed, owned and operated by customers or third parties rather than the utility. Increased customer and third-party investment on the electric system can offer a variety of economic and environmental benefits including, but not limited to, the possibility of reducing the need for ratepayer-funded distribution infrastructure investments. In other words, not only are customers and third parties impacting the system in new ways, but they are also now able to become part of the solution set to address grid needs through their own investment choices.[10]

In the utility industry today, the question is rapidly shifting from "should DER be allowed to expand across the grid?" to "how can the growth of DER be enabled in a manner that supports customer demands, maintains grid reliability and ensures reasonable costs?"[11] Distribution planning must adapt to this increased complexity in order to become a valuable tool for not only guiding utility investment, but also customer and marketplace activity.[12]

Leading regulators and utilities are recognizing this opportunity and are developing ***Integrated Distribution Planning*** (IDP) processes in response. IDP expands upon the current distribution planning process (see *Figure 2*)

9 Rhode Island, p. 43
10 *Id.*
11 Colman, Wilson, and Chung, p. 21
12 Rhode Island, p. 43

by including:

- Explicit consideration of the impacts from all DER types, including energy efficiency and demand response, in load forecasting and transmission, distribution and integrated resource planning.
- ***Enhanced forecasting*** to reflect the uncertainties of DER growth and its impact on load and peak demands.
- Analysis of the distribution systems' ability to accommodate DER without requiring upgrades. This is commonly referred to as a ***Hosting Capacity Analysis***.
- Identification of ***Locational Value*** for nodes on the distribution system where DER deployment could provide grid services[13].
- Consideration of third-party DER or portfolios of DER to address grid needs as ***non-wires alternatives (NWA)***[14].
- Acquisition of NWA grid services from customers and third parties using ***pricing, programs or procurement***.
- Active monitoring, management and optimization of DER.
- ***Streamlined DG interconnection*** processes using insights from the hosting capacity analysis.
- Increased external transparency through enhanced data availability and ***meaningful stakeholder engagement***.

Utilities and their customers can derive substantial benefits from IDP, including lowering costs to reduce rate pressure in a low load growth environment, creating more cost-effective programs with better returns for customers and shareholders, and enhancing customer relationships as interest in DER continues to grow.[15] Customers and developers will have the opportunity to propose, provide and be compensated for grid services, while experiencing more efficient and predictable interconnection processes. Regulators will benefit from increased transparency and data access for optimal solution identification, more efficient regulatory proceedings, and opportunities for more meaningful engagement with utilities and other stakeholders.[16]

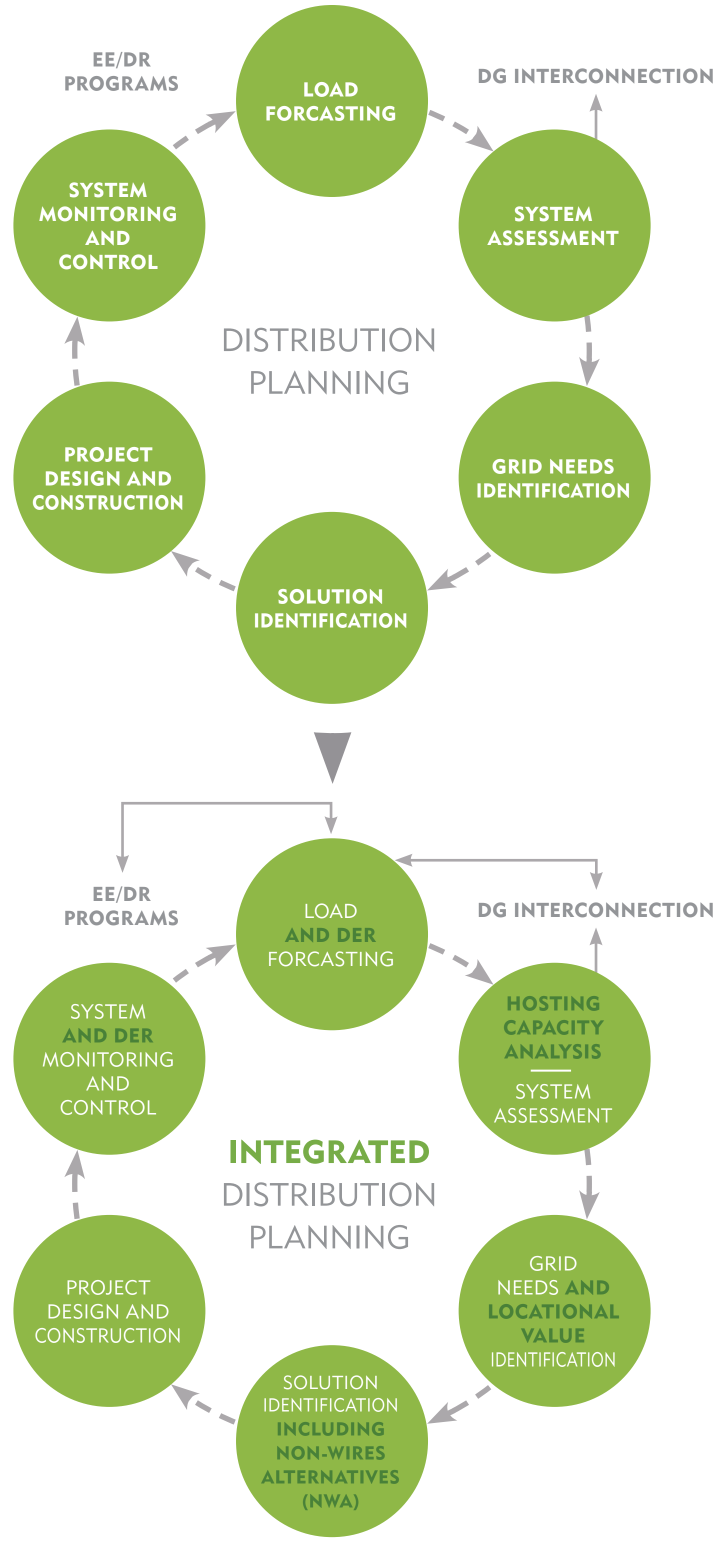

FIGURE 2. Transitioning to Integrated Distribution Planning

13 DER grid services may include peak load reduction or other capacity relief, reactive power support, voltage regulation, frequency regulation, increased hosting capacity, provision of data on asset performance, and enhanced reliability, resiliency or power quality.
14 NWA are deployments of DER or combinations of DER – owned by the utility, customers or other third parties - to defer or avoid the need for investment in conventional, more costly utility infrastructure.
15 Robison, Pickles, Fine, Sakib, and Duffy, pp. 2
16 De Martini, Brouillard, Robison, and Howley

NEW IDP CAPABILITIES

The successful transition to full Integrated Distribution Planning requires the development of five new capabilities, specifically:

1 | Advanced Forecasting and System Modeling

2 | Hosting Capacity Analysis

3 | Disclosure of Grid Needs and Locational Value

4 | New Solution Acquisition

5 | Meaningful Stakeholder Engagement

ADVANCED FORECASTING AND SYSTEM MODELING

An initial step in today's distribution planning process involves the forecasting of load growth and future circuit and substation peak demands over a 5-20 year time horizon. These forecasts are based on circuit and substation loads recorded at the time of previous peaks, adjusted for weather impacts, expected growth rates, and known changes in load such as the addition or loss of major customers.

The resulting forecasts are largely deterministic, meaning they often do not reflect randomness or uncertainty. Utilities apply these static "snapshots" in time and linear extrapolations of historical data to identify where system limits may be exceeded and where upgrades may be required to accommodate load growth. As such, load forecasts are a critical input into a utility's capital expenditure plan and directly impact a utility's revenue requirement. Figure 3 illustrates the deterministic results from a typical utility load forecasting process.

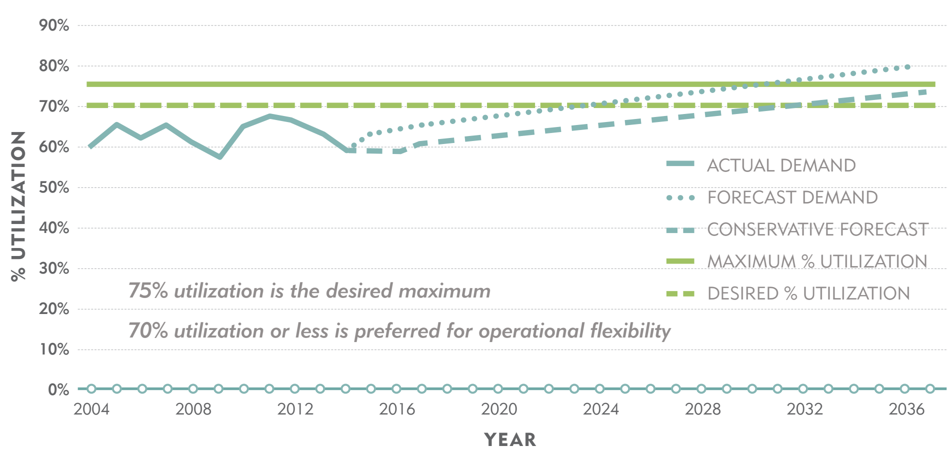

FIGURE 3. Typical Distribution Load Forecasting Results

As DER adoption grows, distribution systems will increasingly experience variability of loading, voltage and other attributes of system performance. New approaches to enhance forecasting in a high-DER future include probabilistic planning and DER adoption scenario analyses. Probabilistic planning, as opposed to the current deterministic approach, accounts for uncertainties introduced by factors such as increasing DER penetration and weather variability. Scenario analyses consider a range of possible futures where varying levels of DER are adopted on the system.[17]

While utilities have well-established methodologies for developing load forecasts, the methodologies for DER forecasting are evolving and the necessary techniques and software tools are still under development. For utilities in the early stages of building this capability, modeling is often based on historical patterns of DER adoption or goals set for utilities.[18] Many leading utilities are using customer-adoption models to forecast expected ***quantities*** of DER, and analysis of individual customers' propensity to adopt based on demographics or load to forecast ***locations*** of DER deployment.[19] Customer-adoption models explicitly use historical DER deployment, location-specific DER technical potential, various DER economic considerations, and end-user behaviors as predictive factors.[20] Table 1 summarizes key steps of an effective DER adoption forecast.

Ultimately, utilities must determine what impacts the adoption of various DER types will have on individual circuit load profiles throughout the year. It is important to know the extent to which DER production is coincident with peak load on each circuit, as well as expected DER output at times of minimum circuit loads.

17 Rhode Island, p. 48
18 Trabish
19 Mills, Barbose, Seel, Dong, Mai, Sigrin, and Zuboy, p. 45
20 *Id.*, p. 7

TABLE 1. Key DER Adoption Forecast Steps[21]

STEP NO.	NAME	DESCRIPTION
1	**Technical Potential**	Estimate the amount of DER capacity that can fit within the physical constraints of each customer site. (For solar PV, the constraint is the amount of unshaded, properly oriented space on the rooftop or the ground available at the site. For other technologies, the constraint may be the electrical panel capacity, natural gas line capacity, customer peak demand, or best available technologies.)
2	**Economic Potential**	Model the economics of DER assets for each customer site to determine the amount of DER capacity that is cost-effective according to a specified financial metric. (Metrics may include levelized cost of energy, payback period, net present value, etc.) This is a subset of the technical potential.
3	**Achievable Potential**	Even if a DER technology is technically feasible and cost-effective, not all customers will adopt it due to other non-technical/non-economic barriers. This step applies an "adoption curve" to estimate what proportion of customers is likely to implement DER technologies (e.g., with a ten-year payback 50 percent of customers will adopt, and with a one-year payback 90 percent of customers will adopt). This is a subset of the economic potential.
4	**Customer-Level Adoption Probability (or "Dispersion Analysis")**	The end result of the DER adoption forecasting process is an adoption probability for each DER technology at each individual customer site, based on the technical/economic/achievable potential calculated in the previous steps. It can also be taken a step further to project how adoption probability will change over time as technical/economic/achievable potential changes (e.g., as technical performance improves or costs decrease). This customer-level adoption probability can be aggregated to calculate the amount of likely DER adoption across an entire distribution circuit, or utility service territory, for distribution planning purposes; or it can be used to select which customers should be targeted for more detailed modeling or for marketing of DER-related programs and services.

DER FORECASTING AT SACRAMENTO MUNICIPAL UTILITY DISTRICT (SMUD)

Like many other utilities, SMUD is seeing increasing adoption of customer-owned and third party-owned DER in its territory. SMUD recognized an opportunity to proactively plan for this DER deployment to minimize extra costs to the grid, maximize grid benefits, and optimize grid investments around the most likely DER deployment scenarios.

SMUD forecasted adoption of various DER technology types through 2030 at the individual customer level and concluded:

- Adoption of DER will be widespread throughout the utility's service territory, mostly resulting in annual net load reductions.
- Adoption will be uneven, with "clustering" of high DER adoption driven by demographics, and technical and economic factors. This unevenness could lead to "hotspots" of distribution grid impacts, the need for mitigation solutions, and opportunities for proactive system planning and customer engagement.

SMUD intends to use the rich customer database developed through this analysis to improve targeting of future customer-focused DER programs and incentives like community solar. It could also be used to identify optimal locations for new infrastructure, such as DC fast charging stations for EVs.[22]

Planners will require modeling of load and DER performance on an hourly or sub-hourly basis to accurately assess distribution system dynamics. Time Series Power Flow Analysis (TSPFA), which can help to analyze the effects of solar irradiance variations or wind fluctuations on power system controls, such as voltage regulators, load tap changers, and switched capacitors, has increasing importance. Although offered in most distribution planning commercial software tools, TSPFA is not widely adopted and used by utilities due to its nascence, relative complexity, and the lack of suitable

21 Colman, Wilson, and Chung, p. 18
22 Smart Electric Power Alliance, Black & Veatch

data for time-varying inputs.[23]

Traditionally, utilities conduct power system analysis separately for transmission and distribution. Conventional distribution system models aggregate the entire bulk power network into a single connection point, while transmission system analysis models distribution systems as aggregated loads. With the increasing penetration of DER on distribution systems, the net-load characteristics from DER can affect transmission, and the wholesale energy and ancillary services provided by DER can be delivered across the distribution system to the transmission system. Therefore, utilities will require an integrated view of transmission, distribution, and DER to analyze the interaction of the systems.[24]

Upcoming revisions to the industry technical standards for inverters will also require new utility system modeling capabilities. Today's inverters, which provide the interface between many DER and the grid by converting direct current (DC) power to alternating current (AC) power, provide limited functionality beyond disconnecting during system disturbances. A significant 2018 revision to the industry standard for interconnection and interoperability of DER[25] will require many additional functions for all new inverters, including abilities to provide additional grid services.[26] As customers adopt DER with new "smart" inverters, regulators and distribution utilities must modify interconnection requirements and develop the modeling capabilities for these advanced functions to fully utilize these new grid resources.

Each utility will also need to develop new capabilities for operating an increasingly complex distribution system, as well as monitoring, managing, and optimizing DER connected to its circuits. Advanced Distribution Management Systems (ADMS) and DER Management Systems (DERMS), though still in various stages of definition[27] and development, will become standard tools in the toolbox of distribution planners.

23 Tang, Homer, McDermott, Coddington, Sigrin, and Mather, p. iii
24 Tang, pp. 21-22
25 Institute of Electrical and Electronics Engineers (IEEE) Standard 1547. The revised IEEE standard requires Authorities Governing Interconnection Requirements (i.e., public utility commissions) to modify interconnection standards and define required functions and settings for advanced inverters.
26 For example, "smart" or advanced inverters can ride through (not disconnect during) minor voltage and frequency disturbances, enhancing system stability. They can also inject or absorb reactive power to provide voltage regulation services
27 http://www.elp.com/articles/2018/01/sepa-collaborators-tackle-derms-standards-prior-to-distributech.html

HOSTING CAPACITY ANALYSIS

A Hosting Capacity Analysis (HCA) has emerged as a critical capability for proactively managing increased adoption of DER while maintaining grid reliability and safety. The term "hosting capacity" refers to the amount of DER that a circuit can accommodate without adversely impacting power reliability or quality under current configurations, and without requiring mitigation or infrastructure upgrades.[28]

HCA allows utilities, regulators, customers, and DER developers to make more efficient and cost-effective decisions about whether to pursue interconnection of a DER technology at a specific grid location by providing data about the amount of new DER that can be accommodated at a particular node on the grid. Mapping the hosting capacity of the entire distribution grid provides even more powerful benefits: customers can identify optimal locations to install and interconnect DER; regulators and utilities can develop price signals to direct DER to locations on the grid where they can provide the greatest benefit; and utilities can better plan for grid infrastructure improvements that expand hosting capacity at locations with high demand for DER.[29]

A circuit's hosting capacity is not a single number, but rather a range of values depending on the DER type and where the DER is located on the circuit. Hosting capacity for generating DER, such as solar PV, is typically higher closer to the substation than it is at locations further away. A circuit's hosting capacity also varies significantly between DER technologies and is impacted by feeder characteristics such as feeder length, voltage class, conductor size, voltage regulation equipment, system protection settings, and the circuit's load profile.

There are currently four accepted methodologies for conducting an HCA – Stochastic, Streamlined, Iterative, and EPRI's Distribution Resource Integration and Value Estimation (DRIVE) method. Each provides different levels of accuracy and requires different levels of computational intensity. Table 2 summarizes the characteristics of each HCA methodology.

The choice of HCA methodology and the associated data and tool requirements should follow a thoughtful consideration of what value the hosting capacity analysis is intended to provide and what the results will be used for (i.e., its "use cases"). Only by understanding

28 Lew, p. 22
29 Stanfield and Safdi, p. 1

TABLE 2. Hosting Capacity Methodologies[30]

METHOD	APPROACH	ADVANTAGES	DISADVANTAGES	COMPUTATION TIME	RECOMMENDED USE CASE
Stochastic	• Increase DER randomly • Run power flow for each solution	• Similar in concept to traditional interconnection studies • Becoming available in planning tools	• Computationally intensive • Limited scenarios	Hours/feeder	• DER planning
Iterative (Integration Capacity Analysis)	• Increase DER at specific location • Run power flow for each solution	• Similar in concept to traditional interconnection studies • Becoming available in planning tools	• Computationally intensive • Limited scenarios • Vendor-specific implementations can vary • Does not determine small distributed (rooftop PV)	Hours/feeder	• Inform screening process • Inform developers
Streamlined	• Limited number of power flows • Utilizes combination of power flow and algorithms	• Computationally efficient • Not vendor tool specific	• Novel approach to hosting capacity • Not well understood method • Limited scenarios • Not available in current planning tools	Minutes/feeder	• Inform screening process • Inform developers
DRIVE	• Limited number of power flows • Utilizes combination of power flow and algorithms	• Computationally efficient • Many DER scenarios considered • Not vendor tool specific • Broad utility industry adoption and input • Becoming available in planning tools	• Novel approach to hosting capacity • Not well understood method • Lag between modifications/ upgrades and associated documentation	Minutes/feeder	• DER planning • Inform screening process • Inform developers

the intended output and use case(s) of the HCA results can parties identify the right methodology, tools and required data. This should be a shared understanding among utilities, regulators, and other stakeholders, allowing for clear expectations, agreement on necessary investments and appropriate use of the HCA results.[31]

HCA use cases may include:

- Providing customers and DER developers with visibility into circuit locations that can accommodate DER at minimal cost.
- Streamlining DER application and interconnection processes by replacing less accurate rules-of-thumb used in technical screens.
- Identification of opportunities for proactive investment in circuit modifications or upgrades to increase hosting capacity.

Mapping the hosting capacity of all circuits and making these results publicly available can guide customers and DER developers to locations where they can provide more value to the grid and minimize project costs.[32] User-friendly maps displaying HCA results and downloadable data files also help customers understand what project sizes and technologies can be most easily accommodated in a particular location, which can help them better predict the cost and timeline of the interconnection process. Giving customers the ability

30 Smith, p. 2
31 Succar, pp. 2-4

32 For example, see the NY joint utilities hosting capacity maps available at http://jointutilitiesofny.org/utility-specific-pages/hosting-capacity/ and the Pepco Holdings' maps available at https://www.pepco.com/MyAccount/MyService/Pages/MD/HostingCapacityMap.aspx

to self-select optimal interconnection sites will in itself speed up the interconnection process by channeling applications to the grid locations where they are most likely to be quickly approved.[33]

FIGURE 4. Hosting Capacity Results[34]

It is important for regulatory commissions to establish common use cases and require consistency in HCA methodologies across its utilities, as it will simplify the implementation and oversight process, while also ensuring a more consistent and efficient utilization of the tool by customers and DER developers. Each utility adopting a different methodology with varying suitability to statewide use cases will likely result in more confusion among those attempting to use the HCA and reduce efficiencies for all, including utilities and regulators. Consistent methodologies among utilities also allows for peer learning and exchange of information, which will help improve the accuracy and functionality of the HCAs over time.[35]

DISCLOSURE OF GRID NEEDS AND LOCATIONAL VALUE

As described previously, today's distribution planning is a closed process with minimal regulator and stakeholder visibility into the rationale for planned projects and the underlying grid needs the projects will address. As customers increasingly adopt distributed energy solutions, many utilities are thinking proactively about how to integrate DER into planning to take advantage of these technologies. For utilities that want to manage DER growth or actually leverage these technologies to reduce costs and improve customer relationships, understanding the value of DER on a locational basis and publishing this understanding is a key capability. Increasing the transparency of grid needs and revealing the potential value of deploying DER at specific locations on the grid allows a utility to collaborate with customers and developers to design more effective tariffs, implement cost effective non-wires alternatives, improve demand-side management programs, and animate the market for DER.[36]

As part of the utility planning process described previously, utilities identify grid needs, conventional solutions to address the needs, and the costs of the conventional solutions. One way to determine locational value of DER is based on the contribution the resources could make to addressing the need and the time value of money of deferring or avoiding the conventional solution. Figure 5 illustrates this concept for the deferral of a capacity-related investment.

The New York Reforming the Energy Vision (REV) process provides guidance on how to estimate the avoided distribution capacity value of DER in its Benefit Cost Analysis Framework. It requires utilities to estimate the value of avoided T&D based on the latest detailed marginal-cost-of-service studies. One of the primary drivers of this cost will be how close the system is to reaching capacity. Reducing the peak load for equipment that is near capacity will provide more deferral value than reducing it for equipment with significant excess capacity.[37]

In addition to identifying locational value, utilities must make this information publicly available in a way that

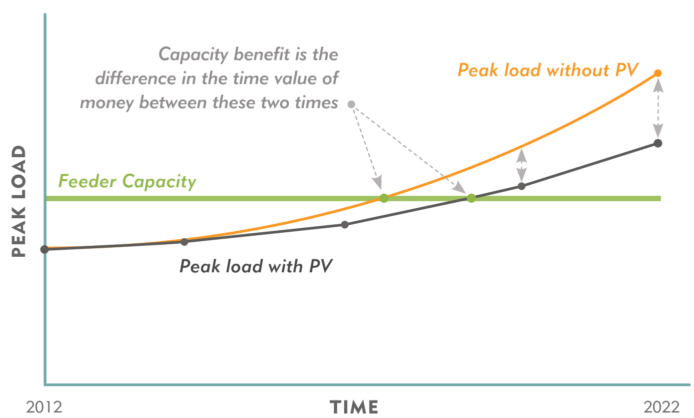

FIGURE 5. Distribution Capacity Deferral Value of DER[38]

33 Stanfield and Safdi, p. 8
34 From Southern California Edison's DER Interconnection Map (DERiM), available at https://drpwg.org/sample-page/drp/
35 Stanfield and Safdi, p. 30

36 Robison, Pickles, Fine, Sakib, and Duffy, p. 1
37 Mills, Barbose, Seel, Dong, Mai, Sigrin, and Zuboy, p. 53
38 Mills, Barbose, Seel, Dong, Mai, Sigrin, and Zuboy, p. 53

motivates DER development at beneficial locations on the grid. For example, each utility in New York now publishes a Distributed System Implementation Plan (DSIP) every two years, which includes identification of specific areas where there are impending or foreseeable infrastructure upgrades needed, such that NWAs could be considered and so that DERs could potentially provide delivery infrastructure avoidance value or other reliability or operational benefits. The utilities have been directed by the NY PSC to list specific infrastructure projects by location and indicate the potential for DERs to address the forecasted system requirements.[39]

The NY utilities also publish heat maps showing where DER can help address system needs, such as load growth or voltage regulation in areas with highly utilized feeders. The heat maps provide a complementary benefit to hosting capacity maps: whereas hosting capacity maps show where DER can avoid creating problems, heat maps reveal where DER can help address problems (e.g., by reducing congestion or peak loads on an overloaded feeder). The heat maps are intended to help direct third-party investment toward areas on the grid where DER can help reduce, defer, or avoid conventional utility infrastructure projects.[45]

California is establishing a Distribution Investment Deferral Framework where its utilities will publish an annual Grid Needs Assessment (GNA), showing grid needs, planned investments, and candidate deferral projects using online maps and downloadable datasets. Importantly, the GNA will describe the performance requirements for any DER solution, including the magnitude, duration and frequency of resources required to address each grid need. The Locational Net Benefits Analysis (LNBA) framework, which includes a broad range of system and societal benefits[46], is the basis for determining the range of value at each location. The utilities and stakeholders are developing prioritization metrics by which to characterize candidate deferral opportunities and identify projects with a high likelihood of successful, cost-effective investment deferrals.[47]

OTHER EXAMPLES OF NON-WIRES ALTERNATIVES (NWA)

- **Tiverton/Little Compton**
  National Grid's deployment of targeted EE and DR to defer a $2.9 million substation upgrade in Rhode Island[40]
- **Boothbay**
  Deployment of 1.6 MW of EE, DR, PV, storage and backup generation to avoid an $18 million transmission upgrade proposed by Central Maine Power[41]
- **Borrego Springs**
  San Diego Gas & Electric's deployment of a solar, storage, and backup generation microgrid for improved reliability at a cost 3-4 times cheaper than the conventional transmission alternative[42]
- **Punkin Center**
  Arizona Public Service's deployment of 1 MW / 4 MWh of battery storage to defer a distribution system upgrade[43]
- **Minster, OH**
  Deployment of 4.2 MW of solar and 7 MW of storage that, among other value streams, avoided the need for $350k of grid upgrades to improve power quality for industrial customers[44]

Utilities have successfully deployed NWA to address capacity, voltage, reliability and power quality grid needs, but not all distribution projects are suitable for deferral or avoidance by DER and candidates for NWA consideration. For example, replacements of distribution system components due to age or poor condition (rather than capacity constraints) typically do not qualify for NWA.

Leading jurisdictions are establishing criteria for identifying the suitability of projects for NWA. For example, Rhode Island's System Reliability Procurement (SRP) NWA criteria define the type,

39 NY PSC Order Adopting Distributed System Implementation Plan Guidance Order, April 20, 2016.http://www.raabassociates.org/Articles/NY%20PSC%20%282016%29%20DSIP%20Guidance%20Order.pdf

40 http://www.ripuc.org/eventsactions/docket/4581-NGrid-2016-SRP(10-14-15).pdf

41 http://www.neep.org/sites/default/files/resources/FINAL_Boothbay%20Pilot%20Report_20160119.pdf

42 https://www.greentechmedia.com/articles/read/distributech-roundup-microgrids-on-the-march#gs.vaxlsco

43 https://www.greentechmedia.com/articles/read/aes-buys-energy-storage-for-less-than-half-the-cost-of-a-wires-upgrade#gs.ZwQU0v0

44 https://sepapower.org/knowledge/a-small-town-in-ohio-creates-industry-buzz-with-solar-plus-storage/

45 Rhode Island, p. 50

46 Avoided transmission and distribution capital and O&M, voltage and power quality, reliability and resiliency, avoided energy and GHG, avoided losses, other ancillary services and safety/societal benefits

47 See CPUC Docket R.14-08-013 et al., Proposed Decision on Track 3 Policy Issues, Sub-track 1 (Growth Scenarios) and Sub-track 3 (Distribution investment and Deferral Process), 12/8/17

size, and minimum cost of projects that qualify for consideration.[48] In 2017, the most recent triennial update to the SRP Standards included several key revisions including: (1) the use of NWA to address new types of distribution system needs beyond load-growth related issues (e.g., voltage performance, communication systems); (2) the use of NWA to proactively target "highly-utilized" areas of the distribution system with NWA to extend the life of existing equipment; and (3) consideration of "partial NWA" that reduce the scope of infrastructure projects (rather than defer the entire project).[49]

Other regulatory commissions could follow this approach by defining the criteria for types of projects that qualify for NWA, requiring the utilities to identify candidate projects that meet the criteria, and conducting NWA pilots in each utility service territory to validate the effectiveness of the DER solutions. The result would ideally establish a workable process for substituting DER for more expensive grid investments, saving customers money and expanding the DER market.

NEW SOLUTION ACQUISITION

Once utilities have successfully identified and disclosed grid needs, locational value and opportunities for NWA, they must establish the capability to acquire or source the alternative solutions in order for customers and the market to benefit from this new information.
As previously described, the process starts with clearly defined and transparent disclosure of grid needs and performance requirements. Utilities define a set of discrete services and performance levels to meet the operational requirements that, if provided by DER, could effectively substitute for conventional infrastructure projects. These services are typically defined in a neutral manner rather than specifying a pre-determined DER technology.[50]

DER providers then have the opportunity to propose solutions to the utilities that meet the requirements. As the party responsible for the planning process, the utility may assess the alternatives, determine the preferred solution for each need, and then report and explain its recommendations for stakeholder consideration and regulatory approval.[51]

There may be a need to assign an independent, impartial entity to conduct the analysis and develop the recommended portfolio of solutions for regulatory approval if the alternatives have material impacts on a utility's revenue and profitability. A utility could perform this function as long as there is sufficient transparency and regulatory oversight to insure fair consideration of alternative proposals.[52]

In California, review of the Grid Needs Assessments and facilitation of the DER solution solicitation process will be managed by a Distribution Planning Advisory Group, staffed with utility engineers, Commission technical staff, DER market providers, non-market participants, and facilitated by an independent professional engineer.

Potential alternatives to any grid need likely involve a range of solutions that utilities may source through one or more of the following mechanisms:

- **Pricing**
  DER services provided in response to time-varying rates, tariffs and market-based prices. This may involve modifying/targeting existing or designing new dynamic pricing options to deliver locational benefits. For example, Salt River Project (SRP) in Arizona has determined that time-of-use (TOU) price plans are effective at incentivizing electric vehicle drivers to charge later than they normally would, which will help SRP meet customer demand without the need to add infrastructure.[53]
- **Programs**
  DER deployed through programs operated by the utility or third parties with funding by utility customers through retail rates or by the state.[54] This again may involve modifying/targeting existing or designing new programs to deliver locational benefits. For example, Central Hudson Gas & Electric's Peak Perks program targets deployment of Wi-Fi-enabled smart thermostats and pool pump controls on specific circuits to reduce peak loads and postpone or avoid system upgrades.[55]
- **Procurement**
  DER services sourced through competitive solicitations. In addition to the NWA shown on page 14, a commonly cited example of this is the Brooklyn/Queens Demand Management program. ConEd conducted auctions to procure energy efficiency, demand response, storage, and other solutions expected to result in more than 22 MW of

48 http://www.ripuc.org/eventsactions/docket/4684-LCP-Standards_7-27-17.pdf, p. 14
49 http://www.ripuc.org/utilityinfo/electric/DSP_Workstream_proposals_8_15.pdf, p. 7
50 De Martini and Kristov, p. 41
51 *Id.*, pp. 41-42

52 *Id.*, pp. 42-43
53 http://www.elp.com/articles/2018/01/salt-river-project-provides-results-of-electric-vehicles-study.html
54 De Martini and Kristov, p. 42
55 http://hudsonvalleynewsnetwork.com/2016/07/17/reducing-peak-energy-use-targeted-areas/

demand reduction in afternoon and evening hours[56], contributing to the deferral of a new $1.2 billion substation.

Determining an optimal mix from these three categories, plus any grid infrastructure investments, requires both a portfolio development approach and a means to compare each alternative's attributes such as resource dependability, response time and duration, load profile impacts, deployment times, and net benefits (net of the costs to integrate DER into grid operations).[57]

The portfolio assessment to determine the preferred solution for each grid need should use a pre-approved methodology through a transparent regulatory process involving all interested stakeholders. Ideally, approval of a portfolio would be the responsibility of the regulator in the context of its approval of a comprehensive distribution plan.[58]

In addition to transparency and fairness, it is important that the sourcing mechanisms result in DER compensation that is long-term, stable, and financeable. Utilities benefit from a regulatory structure that offers capital returns needed to make long-term investments. This proven mechanism has enabled utilities to confidently finance billions of dollars of assets to meet the needs of customers and society. Financial markets view this favorably, which ultimately results in a lower cost of capital for the incumbent utility and lower costs for its customers. DER providers do not have such regulatory guarantees, but they should be afforded similar long-term assurances for the resources they deploy in lieu of conventional utility infrastructure. Compensation for the locational value of DER should recognize the long-term value of the resources and, assuming the resources reliably and consistently perform as required, be structured to provide a consistent revenue stream over the life of the assets to ensure ease of financing.[59]

MEANINGFUL STAKEHOLDER ENGAGEMENT

A consistent theme throughout this paper – the need to transition from a closed planning process to one that is more open and transparent engaging multiple stakeholders – requires thoughtful design and execution. Unless ordered through contentious rate cases or other regulatory proceedings, it is uncommon for utilities and distribution planners to willingly share system information and accept input on distribution system plans from non-utility stakeholders. It therefore requires new skills, capabilities and a level of trust and collaboration that may be initially uncomfortable for participants. It can also be very time-consuming and requires a high level of commitment from participating stakeholders.

However, a well-designed and executed stakeholder engagement process can provide many advantages over the traditional adversarial regulatory proceedings, such as:

- Providing a forum for information sharing and education, leading to a common understanding of issues and a common vocabulary. With a stronger collective understanding, parties are likely to have more meaningful dialogue focused on the issues that matters most. This benefits all parties, but especially regulators who must navigate an increasingly complex web of technical information and stakeholder interests.[60]
- A narrowing of differences and building of support before engaging in the typical back and forth of regulatory proceedings. This back and forth, largely between lawyers and policy advocates, can result in entrenchment of positions and ultimately win/lose outcomes, as opposed to the development of new and potentially innovative alternatives.[61]
- Producing long-term relationship benefits, opening lines of communication and helping to bridge opposing viewpoints. These processes typically are more inclusive and accessible than regulatory proceedings, providing greater opportunity to get to know people, as opposed to positions and posturing.[62]
- Improving the quality and efficiency of regulatory proceedings by narrowing the issues regulators must rule on. Successful stakeholder engagement enables the resolution of some issues and clarifies areas of genuine disagreement, providing regulators with more complete and concise information about where parties stand on key issues.[63]

Proceedings in California and New York offer contrasting examples of meaningful versus less-meaningful stakeholder engagement. In the California Distribution Resources Plan working groups, the utility and non-utility stakeholders have engaged in productive, iterative, and ongoing negotiations, with the utilities fielding stakeholder questions, responding to

56 https://conedbqdmauction.com
57 De Martini and Kristov, p. 42
58 *Id.*
59 Gahl, Lucas, Smithwood, and Umoff, pp.8-9
60 De Martini, Brouillard, Robison, and Howley, p. 2
61 *Id.*
62 *Id.*, p. 3
63 *Id.*

recommendations and concerns, and interacting with stakeholders about possibilities during in-person and web-based working group meetings and through written comments. This interactive process has enabled non-utility stakeholders to play a meaningful role in shaping the assumptions, methodologies and outcomes. It also helps stakeholders understand and often support utility approaches that might otherwise seem objectionable.[64]

In contrast, stakeholders in New York's Reforming the Energy Vision engagement groups reported that utilities had already made critical decisions before talking to stakeholders at engagement group meetings. When stakeholders provided input, the utilities did not consistently report back during the working group process about what input would or would not be taken into account, therefore missing opportunities for the iteration and discussion that could lead to consensus. As a result, the meetings seemed to serve more as an opportunity to inform stakeholders of utilities' plans than a meaningful opportunity for stakeholders to help shape the outcomes of the process.[65]

Best practices and keys for success in meaningfully engaging stakeholders in IDP processes include the following.

- **Clear regulatory relationship.** Whether the process is voluntary or ordered, it is important to have clarity around the role of regulators and if and how the process will intersect with or lead to related regulatory proceedings. Without it, participants may be hesitant and likely will not commit their full attention and resources to the process, which risks rendering the process irrelevant.[66]
- **Clear objectives, guiding principles, process parameters and effective organization structure.** It is important to define the purpose and desired outcomes of a process and reach a common understanding of what a process is and is not intended to achieve. A stakeholder process that has as its goal a set of consensus recommendations will be operated and structured differently than a process designed primarily to educate stakeholders or seek input without reaching consensus. Particularly for the more intensive and interactive stakeholder processes, establishing guiding principles and ground rules for participation help create a level playing field and fosters open dialogue.

  Effective stakeholder engagement also requires the governance and quality assurance of a thoughtfully designed organizational structure. An advisory board may be helpful to provide guidance on the objectives, scope, schedule, and deliverables for working-level stakeholder engagement. Stakeholder working groups provide a forum for subject matter experts to more fully address technical issues. Beyond an advisory board and working groups, open stakeholder sessions to educate a broader audience of people and gain additional input on a refined set of topical aspects may be desirable.[67]
- **Open Membership.** Membership in the stakeholder group should be open to all those who wish to participate to ensure diversity of perspectives and optimal buy-in from interested and affected parties. It may be possible to designate representative members from different groups of stakeholder interests to better manage input, but this needs to be done without unnecessarily constraining party participation. If the process includes written comments, there may need to be active efforts by the Commission to elicit sufficient participation to ensure an adequate range of perspectives are considered.[68]
- **Neutral Facilitation and Reporting.** A knowledgeable, skilled, and objective facilitator is critical. Ideally, the facilitator will be a neutral party, either selected from within the Commission or from a third party, rather than selected and appointed by the utilities. The facilitator should be knowledgeable about the subject matter and also have experience and skills in stakeholder engagement. The facilitator should ensure effective and neutral reporting of stakeholder group outcomes, including producing detailed minutes and reports with stakeholder input. If written comments are used in lieu of a working group, it is important to ensure stakeholder comments are considered by the utilities and that the decision makers are provided with a complete understanding of party perspectives.[69]
- **Active Utility Engagement.** Utilities should be required to actively participate in the stakeholder process. When utilities participate only passively, stakeholders may not be informed of utility concerns and/or may feel that their concerns are not being sufficiently considered by the utilities. There should also be checks in place to ensure that utilities are meaningfully considering stakeholder insights and revising their methods where appropriate based on

64 Stanfield and Safdi, p. 26
65 *Id.*
66 De Martini, Brouillard, Robison, and Howley, p. 4
67 *Id.*, pp. 5-6
68 Stanfield and Safdi, p. 25
69 *Id.*, pp. 25-26

TABLE 3. Data for Designing Non-Wires Alternatives[71]

DATA NEED	DESCRIPTION
Circuit Model	The information required to model the behavior of the grid at the location of grid need.
Circuit Loading	Annual loading and voltage data for feeder and SCADA line equipment (15 min or hourly), as well as forecasted growth.
Circuit DER	Installed DER capacity and forecasted growth by circuit.
Circuit Voltage	SCADA voltage profile data (e.g., representative voltage profiles).
Circuit Reliability	Reliability statistics by circuit (e.g., CAIDI, SAIFI, SAIDI, CEMI).
Circuit Resiliency	Number and configuration of circuit supply feeds (used as a proxy for resiliency).
Equipment Ratings, Settings, and Expected Life	The current and planned equipment ratings, relevant settings (e.g., protection, voltage regulation, etc.), and expected remaining life.
Area Served by Equipment	The geographic area that is served by the equipment in order to identify assets which could be used to address the grid need. This may take the form of a GIS polygon.

those insights.[70]

- **Consensus-Building.** Regulators and facilitators should ensure that the process maximizes opportunities for stakeholders to actively voice their perspectives and concerns. Working group meetings and discussions should promote active dialogue among stakeholders in order to build consensus. Where there are areas of disagreement, there should be opportunities to communicate divergent views to utilities and regulators, including through stakeholder reports.[72]
- **Easy Access.** Access to stakeholder meetings and results should be made as easy as possible. Measures to optimize access include publicizing stakeholder meetings well in advance, holding meetings in a neutral location, establishing a mix of in-person and teleconference meetings, employing technology to maximize meaningful participation, and maintaining detailed minutes. Minutes, reports, and other stakeholder group documents should be posted in an accessible electronic forum to allow interested parties to keep track of proceedings.[73]

Data Sharing

An effective stakeholder engagement process also requires sharing of system data to enable effective collaboration. Utilities are caught between competing demands to increase transparency by sharing more data with interested stakeholders and mandates to ensure high levels of physical and cyber security. Clearly, DER customers and developers can benefit from greater grid data, but utilities can also benefit from data on DER performance and costs, and parties will need to negotiate requirements for data sharing in both directions. This is still an area of very active debate in many states, and each jurisdiction will have to determine what data is appropriate to share and what should be kept confidential. One potential compromise, similar to the CA Distribution Planning Advisory Group described earlier, is allowing greater grid data access to a limited stakeholder group that can review utility plans and provide objective, outside feedback.[74]

There are a number of foundational reasons to actively promote grid planning and operational data sharing:

- **Informing optimal locations for investment and economic development.** Should customers and developers pursue projects on a specific feeder, or at a specific feeder location? Do DER providers have enough business opportunities to retain local employees? Should DER providers open a warehouse/office in a specific geographic area?[75]
- **Supporting industry innovation.** Additional industry stakeholder engagement unlocks new and different perspectives on grid design and operations, dramatically increasing the pace of innovation. Third parties can offer expertise to improve grid planning and operations, particularly in areas that are not traditional utility strengths (e.g. data analytics,

70 *Id.*, p. 26
71 SolarCity Grid Engineering, 2016, p. 22
72 *Stanfield and Safdi, p. 27*
73 *Id.*

74 Colman, Wilson, and Chung, p. 23
75 SolarCity Grid Engineering, 2015, p. 11

software development, distributed control).[76]

- **Enabling credible auditing of grid infrastructure investment plans.** Industry stakeholders can suggest alternative means to meet grid investment needs. Underlying data, beyond the publishing of finalized analyses (e.g. deferrable investments) shines a light on the grid investment assumptions, methodology and decision-making criteria. Data transparency is a foundation of ratepayer advocacy and should extend into distribution planning.[77]

Table 3 shows the types of data that are helpful for developers in designing solutions to address grid needs.

Utilities in New York have established data portals for stakeholders to access containing a wide range of planning and system information. For example, National Grid's portal contains information on feeder loading, peak load forecasts, system reliability, hosting capacity, capital investment plans, and potential NWA opportunities.[78] Regulators in Rhode Island are requiring National Grid to publish similar information, stating:

> A new Rhode Island Distribution System Plan (DSP) Data Portal should serve as a clearinghouse for users to access key distribution system and planning data in a central and publicly- accessible online location. Peak load forecasts, capital plans, DSP process descriptions, heat maps, hosting capacity maps, and other key data should be made available through the Portal. Where possible and appropriate, data should be made available in machine-readable format. Annual reporting on Portal performance should occur … and include tracking of key user experience metrics, evaluation of qualitative and/or quantitative costs and benefits, stakeholder feedback, and any proposed improvements. National Grid should develop specific, near-term, new datasets of importance to DSP objectives, (specifically) hosting capacity maps and heat maps.[79]

The utilities in California will create DRP data access portals containing hosting capacity, locational value, grid needs, and NWA deferral opportunities all on the same map and available in downloadable datasets. Users will be able to click between tabs to view various information on the circuit map, and will be able to query and export data in tabular form based on a geographic search or keyword search.[80]

RECOMMENDATIONS AND NEXT STEPS

Although customer adoption of DER in a particular jurisdiction may be lower than the states referenced in this paper, it is not too early for regulatory commissions to take proactive steps toward establishing the new capabilities required for Integrated Distribution Planning. In order for utilities to understand the opportunities and risks in an accelerated DER adoption environment and for their customers to fully realize the benefits, utilities need to be addressing their planning frameworks and performing analyses, at least on a pilot basis, well in advance.[81]

A key decision for each commission is the extent to which it values the importance of opening up the distribution planning process and establishing an open market for distribution grid services. FERC's recent Order 841 takes steps to remove unnecessary barriers to participation for energy storage in wholesale markets to ensure just and reasonable wholesale rates.[82] Each commission must decide if additional customer benefits and cost savings are available by eliminating barriers for third-parties to provide DER grid services at the retail distribution level.

GridLab recommends the following next steps for regulatory commissions in the early stages of transitioning to IDP:

1 | Establish clear objectives and guiding principles for the development of IDP, including the extent to which the commission will establish an open market for distribution grid services. Table 4 provides examples from CA, NY, RI and MN for consideration, but ultimately the objectives and principles must reflect the specific priorities of each commission for its electricity consumers.

76 Technet, SunSpec Alliance, and DBL Partners, pp. 2-3
77 *Id.*, p. 3
78 http://ngrid.maps.arcgis.com/apps/MapSeries/index.html?appid=4c8cfd75800b469abb8febca4d5dab59&folderid=8ffa8a74bf834613a04c19a68eefb43b#map
79 Rhode Island, p. 50
80 CPUC Proposed Decision on Track 3 Policy Issues, Sub-track 1 (Growth Scenarios) and Sub-track 3 (Distribution Investment Deferral Process), 12/8/17, http://docs.cpuc.ca.gov/SearchRes.aspx?docformat=ALL&docid=199995533
81 Fine, De Martini, and Robison, p. 7
82 https://ferc.gov/media/news-releases/2018/2018-1/02-15-18-E-1.asp#.WoslyGbMyqB FERC is expected to rule on market participation for aggregated DER sometime in 2018.

2 | Require each utility to file a report describing its distribution planning process today and any planned improvements or investments in improved capabilities. These reports will reveal similarities and differences in utility approaches and provide a common understanding of the starting points for each utility in building new capabilities for the transition to IDP. After submission, the commission should allow stakeholders to comment on the reports. Each report should, at minimum, address:

a. System characteristics, including total customers served, number of circuits and substations, % of substations with SCADA, AMI coverage (% of customers).

b. Overview of the distribution planning process, including frequency, duration and roles/ responsibilities of organizations involved.

c. Categories of projects that result from the planning process, types of projects in each category, and % of expenditures in each category.

d. Planning assumptions including growth rates and design criteria.

e. Load and DER forecasting methods.

f. Software tools used for planning, including forecasting, system modeling and mapping, power flow analysis, system protection, and hosting capacity analysis.

g. Linkages between distribution, transmission, and any integrated resource planning processes

h. Existing DER (all types) connected to the distribution system.

i. Overview of DG interconnection processes including technical screening rules for fast-tracking applications.

j. Interconnection request volumes, average time to approve applications.

k. Organization structure for planning and interconnection, including number of full-time equivalent employees, and descriptions of roles and responsibilities.

l. Descriptions of existing and planned energy efficiency and demand response programs, and how they are integrated into distribution planning.

m. Proposed use cases, methodology and timeline for Hosting Capacity Analyses.

n. Proposed NWA suitability criteria, identification of candidate capacity, voltage or reliability projects for NWA pilots.

o. Any relevant planned technology investments (e.g., AMI, ADMS) and how they will be used to support or improve distribution planning.

3. Establish an IDP Technical Working Group applying the best practices for stakeholder engagement referenced in this paper and involving the commission staff, all utilities, and all interested stakeholders. The Technical Working Group should develop recommendations to the commission on the following:

a. Future scenarios for customer DER adoption in the state, and how these scenarios should be incorporated into forecasting and transmission, distribution, and integrated resource planning processes.

b. Modifications to interconnection standards defining required functions and settings for advanced inverters.

c. Development of NWA suitability criteria, process and timeline for implementing pilots identified in the utility reports from step 2.

d. Definition of hosting capacity analysis (HCA) use cases; identification of the appropriate HCA methodology and associated tools and data requirements to satisfy the use cases; a timeline for initial HCA analysis and publication of results for each utility. As described earlier, it is highly preferable to simplify and standardize the HCA process by requiring the utilities to use the same methodology and tools.

e. Development of portals for sharing information on circuit load profiles, peak load forecasts, capital investment plans, hosting capacity maps, heat maps reflecting locational value and other key data.

In conclusion, many states are on the threshold of experiencing significant growth in a variety of DER over the next several years. It is not too early for regulatory commissions in these states to take proactive steps toward establishing the new capabilities required for Integrated Distribution Planning. Customers and the market can benefit from an IDP process that fully realizes the value of this DER and provides direction for its deployment.

TABLE 4. Select Examples of Principles for Grid Modernization and Distribution Planning Reforms

CALIFORNIA PRINCIPLES FOR DISTRIBUTION RESOURCES PLANS[83]	NEW YORK REV PRINCIPLES FOR MARKET DESIGN[84]	RHODE ISLAND GUIDING PRINCIPLES FOR DSP REFORMS[85]	MINNESOTA PRINCIPLES FOR GRID MODERNIZATION[86]
• Distribution planning should start with a comprehensive, scenario driven, multi stakeholder planning process that standardizes data and methodologies to address locational benefits and costs of distributed resources. • CA's distribution system planning, design and investments should move towards an open, flexible, and node-friendly network system that enables seamless DER integration. • CA's electric distribution system operators should have an expanded role in system operations by acting as a technology-neutral marketplace coordinator while avoiding any operational conflicts of interest. • Flexible DER can provide value today to optimize markets and grid operations. CA should expedite DER participation in wholesale markets, unbundle distribution grid operations, create a transparent process to monetize DER services and reduce unnecessary barriers for DER integration.	• Transparency – access to necessary information by market actors, public visibility into market design and performance; • Customer protection – balance market innovation and participation with customer protections; • Customer benefit – reduce volatility and promote bill management and choice; • Maintain and improve service quality and reliability; • Resiliency – enhance ability to withstand unforeseen shocks; • Fair and open competition – design "level playing field" incentives and access policies; • Minimum barriers to entry – reduce data, physical, financial, and regulatory barriers to participation; • Flexibility, diversity of choice, and innovation; • Fair valuation of benefits and costs; • Coordination with wholesale markets; • Promote investments that provide the greatest value to society.	• Distribution System Planning (DSP) reforms should establish specific milestones to achieving the long-term vision, guided by utilities' growing sophistication in DSP data analytics and enabled by increasing system visibility from improvements in grid connectivity and functionality. • Utilities should identify the required resources necessary to achieve material improvements to DSP capabilities and achieve the vision, and include costs of such resources in its rate case filings. • For all DSP reforms, there must be an ongoing process for meaningful review, input, and update of DSP products including: forecasting, data access, DSP data portal, and heat and hosting capacity maps. • As DSP reforms drive increased customer and third-party access to data, utilities and regulators must address all key data privacy and security protections. • Implementation of DSP reforms should achieve consistency across all programs and policies.	• Maintain and enhance the safety, security, reliability, and resilience of the electricity grid, at fair and reasonable costs, consistent with the state's energy policies; • Enable greater customer engagement, empowerment, and options for energy services; • Move toward the creation of efficient, cost-effective, accessible grid platforms for new products, new services, and opportunities for adoption of new distributed technologies; • Ensure optimized utilization of electricity grid assets and resources to minimize total system costs; • Facilitate comprehensive, coordinated, transparent, integrated distribution system planning.

83 Final Guidance Assigned Commissioner's Ruling on Distribution Resource Plans (DRP), pp. 7-8, http://www.cpuc.ca.gov/General.aspx?id=5071
84 New York Department of Public Service Staff Straw Proposal on Track One Issues, p. 16, http://www3.dps.ny.gov/W/PSCWeb.nsf/All/C12C0A18F55877E785257E6F005D533E?OpenDocument
85 Rhode Island, p. 46
86 Minnesota, p. 13

REFERENCES

Acadia Center. 2017. "UtilityVision 2030 - Grid Modernization Companion Brief." May. http://acadiacenter.org/wp-content/uploads/2017/05/Acadia-Center-EnergyVision-2030-Grid-Modernization.pdf

Acadia Center. 2017. "How Can We Replace Traditional Infrastructure With Clean Energy?" July. http://acadiacenter.org/how-can-we-replace-traditional-infrastructure-with-clean-energy/

Anthony, Abigail. 2016. "Community Energy Proving Successful in Boothbay." Acadia Center, January. http://acadiacenter.org/community-energy-proving-successful-in-boothbay/

Anthony, Abigail, Mark LeBel, Jamie Howland, and Daniel Sosland. 2015. "UtilityVision." Acadia Center. http://acadiacenter.org/wp-content/uploads/2015/02/AcadiaCenter_UtilityVision_WebView_S.pdf

Colman, Andy, Dan Wilson, and Daisy Chung. 2017. "Planning the Distributed Energy Future — Volume 1: Emerging Electric Utility Distribution Planning Practices for Distributed Energy Resources." Black & Veatch and Solar Electric Power Association, May. https://sepapower.org/resource/beyond-the-meter-planning-the-distributed-energy-future-volume-i/

Cooke, Alan, and Juliet Homer. "Distribution System Planning and Operations." Presentation, PowerForward Phase 2: Exploring Technologies from the Ohio Public Utilities Commission, Columbus, OH, July 26, 2017. https://www.puco.ohio.gov/index.cfm?LinkServID=017B9492-5056-B562-E184554FFEC47951

De Martini, Paul. 2014. "More Than Smart – A Framework to Make the Distribution Grid More Open, Efficient and Resilient." Resnick Sustainability Institute, California Institute of Technology. http://morethansmart.org/wp-content/uploads/2015/06/More-Than-Smart-Report-by-GTLG-and-Caltech-08.11.14.pdf

De Martini, Paul, and Lorenzo Kristov. 2015. "Distribution Systems in a High Distributed Energy Resources Future." Future Electric Utility Regulation. Lawrence Berkeley National Laboratory, October. https://emp.lbl.gov/sites/all/files/lbnl-1003797.pdf

De Martini, Paul. 2016. "Integrated Distribution Planning." ICF International, August. https://energy.gov/sites/prod/files/2016/09/f33/DOE%20MPUC%20Integrated%20Distribution%20Planning%208312016.pdf

De Martini, Paul, Carolyn Brouillard, Matt Robison, and Annie Howley. 2016. "The Rising Value of Stakeholder Engagement in Today's High-Stakes Power Landscape." ICF, November. https://www.icf.com/resources/white-papers/2016/the-rising-value-of-stakeholder-engagement

Edge, Ryan, Mike Taylor, and K. Kaufmann. 2014. "Benchmarking Utility Organizational Structures: How Renewable Energy is Reshaping the Utility Hierarchy." Solar Electric Power Association (SEPA), September. https://sepapower.org/resource/how-renewable-energy-is-reshaping-the-utility-hierarchy/

Edge, Ryan, Mike Taylor, Nadav Enbar, and L. Rogers. 2014. "Utility Strategies for Influencing the Locational Deployment of Distributed Solar." Solar Electric Power Association (SEPA) and Electric Power Research Institute (EPRI). https://sepapower.org/resource/utility-strategies-for-influencing-the-locational-deployment-of-distributed-solar/

Electric Power Research Institute. 2014. "The Integrated Grid: Realizing the Full Value of Central and Distributed Energy Resources." February. https://www.epri.com/#/pages/product/000000003002002733/

Fine, Steve, Paul De Martini, and Matt Robison. 2017. "On the Grid's Bleeding Edge: The California, New York, and Hawaii Power Market Revolution." ICF, November. https://www.icf.com/resources/white-papers/2017/on-the-grids-bleeding-edge

Gahl, Dave, Kevin Lucas, Brandon Smithwood, and Rick Umoff. 2018. "Getting More Granular: How Value of Location and Time May Change Compensation for Distributed Energy Resources." Improving Opportunities for Solar Through Grid Modernization. Solar Energy Industries Association. January. https://www.seia.org/sites/default/files/2018-01/SEIA-GridMod-Series-4_2018-Jan-Final_0.pdf

Gahl, Dave, Brandon Smithwood, and Rick Umoff. 2017. "Improving Distribution System Planning to Incorporate Distributed Energy Resources." Improving Opportunities for Solar Through Grid Modernization. Solar Energy Industries Association, July. https://www.seia.org/sites/default/files/resources/SEIA-GridMod-Series-2_2017-July-FINAL_0.pdf

Homer, Juliet, Alan Cooke, Lisa Schwartz, Greg Leventis, Francisco Flores-Espino, and Michael Coddington. 2017. "State Engagement in Electric Distribution System Planning." Pacific Northwest National Laboratory , Lawrence Berkeley National Laboratory, National Renewable Energy Laboratory, December. https://emp.lbl.gov/sites/default/files/state_engagement_in_dsp_final_rev2.pdf

Lew, Debbie. "Emerging Distribution Planning Analyses." Presentation, Distribution Systems and Planning Training for Midwest Public Utility Commissioners, January 16-17, 2018. https://emp.lbl.gov/sites/default/files/11._lew_emerging_planning_analyses.pdf

Lindl, Tim, Kevin Fox, Abraham Ellis, and Robert Broderick. 2013. "Integrated Distribution Planning Concept Paper — A Proactive Approach for Accommodating High Penetrations of Distributed Generation Resources." Interstate Renewable Energy Council, May. http://www.irecusa.org/publications/integrated-distribution-planning-concept-paper/

Mills, Andrew, Galen Barbose, Joachim Seel, Changgui Dong, Trieu Mai, Ben Sigrin, and Jarett Zuboy. 2016. "Planning for a Distributed Disruption: Innovative Practices for Incorporating Distributed Solar into Utility Planning." Ernest Orlando Lawrence Berkeley National Laboratory and National Renewable Energy Laboratory, August. https://emp.lbl.gov/publications/planning-distributed-disruption

Mills, Andrew. "Forecasting Load on the Distribution and Transmission System with Distributed Energy Resources." Presentation, Distribution Systems and Planning Training for Midwest Public Utility Commissions, January 16-17, 2018. https://emp.lbl.gov/sites/default/files/10._mills_forecasting_load_with_ders.pdf

Minnesota Public Utilities Commission. 2016. "Staff Report on Grid Modernization." March. http://gridworks.org/wp-content/uploads/2015/06/MNPUC_Staff_Report_on_Grid_Modernization_March2016.pdf

Pearlman, Olivia, and Abigail Anthony. 2017. "Distributed System Implementation Plans in New York – Summary and Analysis." Acadia Center, June 21. http://acadiacenter.org/wp-content/uploads/2017/06/DSIP-Summary-and-Analysis_20170621_FINAL.pdf

Rhode Island Division of Public Utilities & Carriers, Office of Energy Resources, and Public Utilities Commission. 2017. "Rhode Island Power Sector Transformation — Phase One Report to Governor Gina M. Raimondo." November. http://www.ripuc.org/utilityinfo/electric/PST%20Report_Nov_8.pdf

Robison, Matt, David Pickles, Steve Fine, MD Sakib, and Kevin Duffy. 2017. "Turning Locational Value into Real Dollars." ICF, May. https://www.icf.com/resources/white-papers/2017/turning-locational-value-into-real-dollars

Schwartz, Lisa, and Juliet Homer. "PUC Distribution Planning Practices." Presentation, Distribution Systems and Planning Training for New England Conference of Public Utility Commissioners, September 27-29, 2017. https://emp.lbl.gov/sites/default/files/4._schwartz-homer_necpuc_training_20170920.pdf

Smart Electric Power Alliance, Black & Veatch. 2017. "Planning the Distributed Energy Future – Volume II: A Case Study of Integrated DER Planning by Sacramento Municipal Utility District." Beyond the Meter. May. https://sepapower.org/resource/beyond-meter-planning-distributed-energy-future-volume-ii/

Smith, Jeff. "Methods and Application Considerations for Hosting Capacity." Presentation, Hawaiian Electric Integrated Grid Planning Symposium, Honolulu, HI, November 15, 2017. https://www.hawaiianelectric.com/Documents/about_us/investing_in_the_future/igp_symposium/2_4_jeff_smith.pdf

Smith, Jeff, Matthew Rylander, Lindsey Rogers, and Roger Dugan. "It's All in the Plans: Maximizing the Benefits and Minimizing the Impacts of DERs in an Integrated Grid." *IEEE Power and Energy Magazine* Volume 13, Issue 2 (March-April 2015): 20-29. http://ieeexplore.ieee.org/document/7048005/

SolarCity Grid Engineering. 2015. "Integrated Distribution Planning – A holistic approach to meeting grid needs and expanding customer choice by unlocking the benefits of distributed energy resources." September. http://www.solarcity.com/sites/default/files/SolarCity%20White%20Paper%20-%20Integrated%20Distribution%20Planning_final.pdf

SolarCity Grid Engineering. 2016. "A Pathway to the Distributed Grid – Evaluating the economics of distributed energy resources and outlining a pathway to capturing their potential value." February. http://www.solarcity.com/sites/default/files/SolarCity_Distributed_Grid-021016.pdf

Stanfield, Sky, and Stephanie Safdi. 2017. "Optimizing the Grid — A Regulator's Guide to Hosting Capacity Analysis for Distributed Energy Resources." Interstate Renewable Energy Council, December. https://irecusa.org/publications/optimizing-the-grid-regulators-guide-to-hosting-capacity-analyses-for-distributed-energy-resources/

Sterling, John, Ted Davidovich, Karlynn Cory, Alexandra Aznar, and Joyce McLaren. 2015. "The Flexible Solar Utility: Preparing for Solar's Impacts to Utility Planning and Operations." Solar Electric Power Association (SEPA) and National Renewable Energy Laboratory (NREL), September. https://www.nrel.gov/docs/fy15osti/64586.pdf

Succar, Samir. 2017. "Where's the Value In Hosting Capacity Analysis?" ICF, November. https://www.icf.com/resources/white-papers/2017/wheres-the-value-in-hosting-capacity-analysis

Tang, Y, JS Homer, TE McDermott, MH Coddington, B Sigrin, and BA Mather. 2017. "Summary of Electric Distribution System Analyses with a Focus on DERs." Pacific Northwest National Laboratory and National Renewable Energy Laboratory, April. https://epe.pnnl.gov/pdfs/Summary_of_electric_distribution_system_analyses_April_10_FINAL.pdf

Technet, SunSpec Alliance, and DBL Partners. 2016. "Unlocking Grid Data — Enabling Data Access and Transparency to Drive Innovation in the Electric Grid." http://www.dblpartners.vc/wp-content/uploads/2016/12/Grid-Data-Transparency-and-Access-whitepaper.pdf?48d1ff

Tierney, Susan. 2016. "The Value of 'DER' to 'D' - The Role of Distributed Energy Resources in Supporting Local Electric Distribution System Reliability". Analysis Group, March. http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/About_Us/Organization/Divisions/Policy_and_Planning/Thought_Leaders_Events/Tierney%20White%20Paper%20-%20Value%20of%20DER%20to%20D%20-%203-30-2016%20FINAL.pdf

Trabish, Herman K. "How Leading Utilities are Planning for Distributed Energy Resources." *Utility Dive*. Industry Dive, February 6, 2018. Web. Accessed February 9, 2018. https://www.utilitydive.com/news/how-leading-utilities-are-planning-for-distributed-energy-resources/516260/